United States Department of the Interior

NATIONAL PARK SERVICE
Air Resources Division
P.O. Box 25287
Denver, CO 80225-0287

IN REPLY REFER TO:

N3615 (2350)

August 26, 2013

Carl Daly
Air Program Director
Environmental Protection Agency, Region 8
Mailcode 8P-AR
1595 Wynkoop Street
Denver, Colorado 80202-1129

Re: EPA-R08-OAR-2012-0026

Dear Mr. Daly:

The National Park Service has reviewed EPA's proposed Approval, Disapproval and Promulgation of Implementation Plans; State of Wyoming; Regional Haze State Implementation Plan; Federal Implementation Plan for Regional Haze. In our 2009 comments to Wyoming Department Quality (WDEQ), we commended their analyses and requirements for Best Available Retrofit Technology. We also noted that additional installations of Selective Catalytic Reduction (SCR) technology beyond those proposed by WDEQ are cost-effective at Electric Generating Units (EGU) in Wyoming.

We applaud EPA's proposal for Selective Catalytic Reduction (SCR) for Laramie River Units 1-3, Dave Johnston Unit 3, and Naughton Units 1-2. We encourage EPA to set lower emission limits than 0.07 lb/mmBtu for 30-day rolling average, based on current emissions information in the Clean Air Markets database that demonstrate emissions achievable with SCR. We also encourage EPA to apply consistent criteria for cost-effectiveness and visibility improvement for the sources subject to BART. We are concerned to see that EPA has introduced a retrofit factor greater than "1" (the default) for 13 of the 15 EGUs evaluated, without sufficient justification. We question why EPA did not propose SCR for Dave Johnston Units 1, 2 & 4 and Wyodak Unit 1when cost-effectiveness and visibility improvement were greater than for units where EPA is proposing additional controls. We also request that EPA clarify how visibility improvement and costs were weighted in proposing BART control requirements for the Westvaco and General Chemical trona plants. Finally, we have some concerns with the way the BART analysis was done for the units at the Jim Bridger Plant, particularly with regard to affordability issues and retrofit costs. In our enclosed comments we more fully discuss our concerns.

Thank you for the opportunity to comment. We appreciate the opportunity to work closely with EPA and WDEQ to improve visibility in our national parks. If you have questions, please contact Don Shepherd at 303-969-2075 or don_shepherd@nps.gov.

Sincerely,

Susan Johnson
Chief, Policy, Planning, and Permit Review Branch

Enclosure

cc: Steve Dietrich
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National Park Service Comments on EPA Proposed Best Available Retrofit Technology For Sources in Wyoming August 26, 2013

As noted by EPA, in previous comments, the National Park Service asserted that the State overestimated the costs for some control technologies and underestimated the costs for other control technologies. For example, we pointed out problems such as the use of incorrect baseline emissions, overestimation of the ability of Selective Non-Catalytic Reduction (SNCR) to reduce nitrogen oxides (NO_X), underestimation of SNCR reagent (urea) usage and cost, and underestimation of the ability of Selective Catalytic Reduction (SCR) to reduce NO_X. Based on its review of our comments and upon further review of the State's cost and visibility analyses, EPA determined that the State's analyses are flawed in several respects and are therefore inconsistent with the BART Guidelines and statutory requirements. We appreciate EPA's receptiveness to our comments.

We commend EPA for addressing the problems we noted above, for conducting its own cost analyses, for revising its modeling of the visibility improvement,[1] and for re-proposing action on Wyoming's SIP in order to give the public the opportunity to comment on its updated cost and visibility analyses and its proposed determinations based on this new information. However, we still have some overarching comments and concerns.

Control Effectiveness General Comments:

Selective Non-Catalytic Reduction: It has been our experience that the effectiveness of SNCR is highly dependent upon the characteristics of each boiler. EPA states that:

> SNCR typically reduces NO_X an additional 20 to 30% above combustion controls without excessive NH3 slip. NO_X reduction with SNCR is known to be greater at higher NO_X emission rates than lower rates. Accordingly, EPA has estimated that the NO_X reduction from SNCR as 30% for initial NO_X greater than 0.25 lb/ MMBtu, 25% for NO_X from 0.20 to 0.25 lb/MMBtu and 20% for NO_X less than 0.20 lb/MMBtu.

To support this statement, EPA cites a memo[2] from Jim Staudt, Andover Technology Partners (EPA's consultant), but this memo provides no evidence or documentation to support the assumptions that these control levels can be achieved. As we shall show later (regarding Dave Johnston Unit 4), such assumptions—whether or not supported—can significantly affect the outcome of a BART determination, as EPA explained regarding Laramie River:

> Therefore, EPA predicts that the reduction that can be achieved with SNCR at the Laramie River units is 20%, which is much lower than the 48% assumed by Wyoming. This significantly reduces the tons reduced by SNCR which is in turn used in the calculation of cost effectiveness. It also affects the incremental cost effectiveness between SNCR and SCR (both in combination with additional combustion controls).

[1] For example, EPA applied the BART Guidelines which recommend that post-control emission rates be calculated as a percentage of pre-control emission rates.

[2] *Review of Estimated Compliance Costs for Wyoming Electric Generating (EGUs)—Revision of Previous Memo,* memo from Jim Staudt, Andover Technology Partners, to Doug Grano, EC/R, Inc., February 7, 2013, page 7

As we have pointed out in previous comments to EPA, use of incremental costs in this manner is extremely sensitive to bias due to the interjection of control strategies based upon invalid assumptions of control efficiency.

Selective Catalytic Reduction: For SCR, we agree with EPA that on an annual basis SCR can achieve emission rates of 0.05 lb/mmBtu or lower. We recommend that EPA consider that some coal-fired EGUs are achieving lower emissions. For example, our search of the Clean Air Markets Database (CAMD) found seven conventional coal-fired EGUs averaging 0.04 lb/mmBtu or lower on an annual basis in 2012.

Unlike SNCR, for SCR the ability to achieve low NO_X emissions is less a function of boiler characteristics and more a function of SCR design. It is generally accepted that SCR can reduce NO_x emissions by 80 - 90+%. However, the average control efficiency assumed by EPA for all Wyoming EGUs was 75% (74% median value).

The efficiency of NO_x removal is determined primarily by the amount of catalyst used, as pointed out by Hitachi in an email from Hitachi to EPA Region 9 regarding SCR at the Navajo Generating Station (NGS):

> Hitachi would like to clarify the definition of "30-day rolling average." In response to a question from the EPA on SCR NOx performance guarantee, Hitachi replied that a 3 plus 1 SCR design could be designed to guarantee NOx emissions of 0.05 lb/MMBtu on a 30-day rolling average. However, Hitachi also stated that the utility and their engineer need to determine what margin needs to be applied to insure the unit is capable of achieving less than the permit level on a 30-day rolling average. The EPA stated that in an engineering study performed by Sargent and Lundy, that with a NOx permit limit between 0.07 and 0.08 lb/MMBtu the SCR would be designed for 0.05 lb/MMBtu. The difference between 0.05 and 0.07 is the margin necessary for compliance. Therefore, to set the permit level of 0.055 lb/MMBtu on a design of 0.05 lb/MMBtu will be very difficult to achieve. Lowering the design to 0.03 lb/MMBtu will increase the volume of catalyst required and could drive the design to a 4 plus 1 and add significant cost to the project. We agree with the recommendation in the S&L study that a 0.05 design is more appropriate with a 0.07-0.08 permit level.

By underestimating the efficiency of SCR and potentially overestimating the efficiency of SNCR, EPA has overestimated the incremental costs for SCR.

Costs of Control General Comments

We support EPA's use of the Control Cost Manual and the Integrated Planning Model (IPM) to calculate costs. However, we are very concerned to see that EPA has introduced a retrofit factor greater than "1" (the default) for 13 of the 15 EGUs evaluated. The IPM model used by EPA to estimate control costs in Wyoming, already includes retrofit costs in its costing algorithms. It is generally accepted that retrofit projects will incur costs over and above those for a "greenfield" site, and most of those retrofit costs are already included in the database used to generate the IPM algorithms. So, unless a particular situation is so extreme as to warrant an additional retrofit factor, applying a retrofit factor to an algorithm that already includes retrofit costs is double-counting those costs.

Not only is the application of a retrofit factor not mentioned in the Federal Register Notice, its only supporting documentation appears in docket item EPA-R08-OAR-2012-0026-0086[1], "Review of Estimated Compliance Costs for Wyoming Electricity Generating Units (EGUs) - revision of previous memo":

> Selective Catalytic NOx Reduction (SCR) capital cost is estimated using the IPM algorithms with retrofit factors adjusted on a unit by unit basis. The retrofit factor is a subjective factor used to account for the estimated difficulty of the retrofit that is unique to the facility. Because site visits were not possible, the retrofit factor was estimated from satellite images that provide some insight to the configuration of the units and degree of congestion around the site and in the vicinity of where the SCR would be installed. These factors impact the ability to locate large cranes on the site – that impact how the SCR is assembled (are large sections lifted into place or is the SCR "stick built"), how much ductwork is needed, if the SCR must be built onto a large, elevated steel structure or can be built near the ground, and if other equipment must be relocated to accommodate the space of the SCR. When using the IPM capital cost model, retrofit difficulties associated with an SCR may result in capital cost increases of 30 to 50% over the base model. 12
>
> 12 Sargent & Lundy, "IPM Model – Revisions to Cost and Performance for APC Technologies SCR Cost Development Methodology FINAL", August 2010, Project 12301-007, Perrin Quarles Associates, Inc. p 1.

The reference cited by EPA's consultant includes these explanations:

> P1: The least squares curve fit was based upon an average of the SCR retrofit projects. Retrofit difficulties associated with an SCR may result in capital cost increases of 30 to 50% over the base model. The least squares curve fits were based upon the following assumptions:
> • Retrofit Factor =1
>
> P2: A retrofit factor that equates to difficulty in construction of the system must be defined.

A proper estimation of retrofit factors involves more than an inspection of satellite images. For example, EPA Region 8 visited the four-unit Colstrip power plant in Montana before concluding that a retrofit factor of "1" was appropriate. Once such a site visit is conducted, retrofit factors should be developed for each element of the cost analysis[3]—not the "blanket" approach used by EPA here.

Another example is provided by Sargent & Lundy's (S&L) "Constructability Review" (slide 76 of the attachment) for addition of SCR at NGS. NGS consists of three EGUs with the middle unit constrained by a coal conveyor passing through. Even so, S&L estimated that construction effort would be only 25% greater for Unit 2 than for the other two units.

We ask EPA to clarify why they chose to add a retrofit factor greater than 1 (average retrofit factor of 1.33 for 13 of 15 units reviewed) to the costs when retrofit costs are already contained within data used to generate the IPM and when neither WDEQ, Basin Electric, nor PacifiCorp included a comparable retrofit factor.[4] By adding the retrofit factor, EPA has overestimated the costs of SCR. In the case of Dave Johnston Units 1, 2, and 4 and Wyodak Unit 1, this has led

[3] Pages 59-62 of William M. Vatavuk's book, <u>Estimating Costs of Air Pollution Control</u>

[4] According to WY DEQ, "Beginning on page 2-28 of Chapter 2.5.4.2, the manual discusses retrofit cost consideration including the practice of developing a retrofit factor to account for unanticipated additional costs of installation not directly related to the capital cost of the controls themselves. However, PacifiCorp did not present a retrofit factor in their cost analyses."

EPA to propose less-efficient controls than SCR. We discuss this further below under the specific facilities and in Appendix 1.

We also found that EPA's consultant had added 1.2% to the total capital investment of SCR to account for "taxes and insurance." The Control Cost Manual (CCM) says:

> "In many cases property taxes do not apply to capital improvements such as air pollution control equipment, therefore, for this analysis, taxes are assumed to be zero [19]. The cost of overhead for an SCR system is also considered to be zero. An SCR system is not viewed as risk-increasing hardware (e.g., a high energy device such as a boiler or a turbine). Consequently, insurance on an SCR system is on the order of a few pennies per thousand dollars annually [19]."
>
> [19] Staudt, J.E. Status Report on NOx Control Technologies and Cost Effectiveness for Utility Boilers. Published by Northeast States for Coordinated Air Use Management (NESCAUM) and Mid-Atlantic Regional Air Management Association (MARAMA), June 1998.

While it might be appropriate to apply a sales tax (if there is one) to the purchased equipment costs, it is not appropriate to add sales tax to the total capital investment, as EPA did. The BART submittal by PacifiCorp included a 1.1% sales tax and Basin Electric included a 4% sales tax, both of which were applied to the purchased equipment costs. It is unclear if application of a sales tax is appropriate in Wyoming and, if so, what is the correct tax rate? We request that EPA justify these additional costs.

Criteria for BART Determinations

EPA has not been explicit about the criteria used to make its BART determinations. It appears that EPA is relying upon the following factors:

- Average cost/ton not to exceed $3,903 (as at Laramie River #3)
- Incremental cost/ton not to exceed $7,050 (as at Bridger #2)
- Minimum visibility improvement at most-impacted Class I area 0.29 dv (Dave Johnston #2 at Wind Cave)
- Minimum cumulative visibility improvement 0.43 dv (Dave Johnston #2 at Wind Cave and Badlands)

One way to balance costs and visibility improvement suggested by the BART Guidelines is the $/dv method. For EPA's Wyoming BART determinations, this yields:

- A maximum reasonable cost-effectiveness of $27,798,246/dv at Badlands due to application of SCR to Laramie River #3.
- A maximum reasonable cost-effectiveness of $10,140,825/cumulative dv due to application of SCR to Laramie River #2.

EPA's highest "reasonable" equivalent cost-effectiveness value $/dv ($27,798,246/dv at Badlands) still falls below the $31.7 Million/dv value that PacifiCorp recommended as being "reasonable" in its 2007 BART submittal for Dave Johnston Unit #4:

> Analysis of the results for the Badlands NP Class 1 Area in Tables 5-1 and 5-3 and Figures 5- 1 and 5-2 illustrates the conclusions stated above. The greatest reduction in 98th percentile dV and number of days

> above 0.5 dV is between the Baseline and Scenario 1. For example, Table 5-3 shows that the incremental cost effectiveness for Scenario 1 compared to the Baseline is reasonable at $770,000/day and $31.7 Million/dV. However, the incremental cost effectiveness for Scenario 3 compared to Scenario 1 is excessive at $3.39 Million/day and $86.7 Million/dV.

Please note that the "incremental cost" to which PacifiCorp refers is simply the difference between the baseline case and PacifiCorp's preferred scenario.

EPA BART Determinations

Basin Electric's (Basin) Laramie River Station (LRS)

EPA is proposing that the FIP NO_X BART emission limit for Basin Electric Laramie River Unit 1, Unit 2, and Unit 3 is 0.07 lb/mmBtu (30-day rolling average). While we are generally pleased with EPA's proposal, we note that EPA's analysis is based on only 74% NO_X control by the SCRs, and still results in each EGU contributing 0.5 dv to visibility impairment at Badlands National Park. We request that EPA evaluate the feasibility and cost-effectiveness of further NO_X reductions that could be achieved by a more-efficient SCR.

Naughton Power Plant

EPA is proposing that the FIP NO_X BART emission limit for Naughton Unit 1, Unit 2, and Unit 3 is 0.07 lb/mmBtu (30-day rolling average). While we are generally pleased with EPA's proposal, we note that EPA's analysis is based on only 76% NO_X control by the SCRs on units #1 & #2, and 85% control by the SCR on unit #3. This still results in Unit #2 contributing 0.5 dv and Unit #3 contributing 0.9 dv to visibility impairment at Badlands National Park. We request that EPA evaluate the feasibility and cost-effectiveness of further NO_X reductions that could be achieved by a more-efficient SCR.

Dave Johnston Power Plant

Dave Johnston Units 1 and 2: EPA is proposing that the FIP NO_X BART for Dave Johnston Units 1 and 2 is LNBs with OFA at an emission limit of 0.22 lb/mmBtu (30-day rolling average). EPA provided no reason for rejecting addition of SCR even though:

- Cost/ton was $3,300 - $3,400, which is less than the $3,900/ton accepted at Laramie River #3.
- Visibility at the most-impacted Class I area would improve by more than 0.4 dv (which is greater than the 0.3 dv improvement for EPA's proposal for Dave Johnston #2).
- Cumulative visibility improvement would exceed 0.6 dv (versus EPA's proposed 0.43 dv improvement for Dave Johnston #2 at Wind Cave and Badlands)
- Cost-effectiveness is $15 million/dv at Wind Cave (versus $27,798,246/dv at Badlands due to application of SCR to Laramie River #3).
- Cumulative cost-effectiveness is less than $10 million/dv (versus $10,140,825/cumulative dv due to application of SCR to Laramie River #2.)

We believe that SCR is Reasonable Progress for Dave Johnston Units 1 and 2. Not only does the addition of SCR to Dave Johnston Units 1 and 2 pass every "test" by which EPA appears to evaluate BART[5] and RP using EPA's cost estimates, we believe that EPA's application of the maximum retrofit factor (1.5) is unsupported and leads to a significant $1.5 million/yr and $800/ton overestimation of costs. Under the EPA proposal, Dave Johnston Units 1 and 2 would each contribute over 0.9 dv impairment at Wind Cave National Park (and 0.7 dv at Badlands National Park). With addition of SCR, impairment would drop to less than 0.5 dv for each unit.

Dave Johnston Unit 3: EPA is proposing that the FIP NO_X BART emission limit for Dave Johnston Unit 3 is 0.07 lb/mmBtu (30-day rolling average) based upon addition of SCR. While we are generally pleased with EPA's proposal, we note that EPA's analysis is based on only 77% NO_X control by the SCRs on Unit 3. This still results in Unit 3 contributing 0.4 dv to visibility impairment at Wind Cave National Park. We request that EPA evaluate the feasibility and cost-effectiveness of further NO_X reductions that could be achieved by a more-efficient SCR.

Dave Johnston Unit 4: EPA is proposing that the FIP NO_X BART emission limit for Dave Johnston Unit 4 is 0.12 lb/mmBtu (30-day rolling average) based upon LNBs with OFA plus SNCR. EPA proposes to eliminate new LNBs with advanced OFA plus SCR because:

> although the average cost effectiveness [$3,000/ton] and visibility improvement [0.5 dv at Wind Cave, 3.3 dv cumulative] for SCR are within the range EPA has found reasonable in other SIP or FIP actions, we find that the incremental cost of SCR at $11,951/ton is high enough so that it precludes the selection of SCR.

Because EPA is basing its proposal on incremental costs, it is essential that the technologies being compared by evaluated with more precision than exhibited in this proposal. We believe that EPA has overestimated the effectiveness of LNB+OFA+SNCR, underestimated the effectiveness of SCR, and overestimated the cost of SCR.

We are especially concerned with the assumption that SNCR can achieve 0.11 lb/mmBtu on an annual basis or 0.12 lb/mmBtu on a 30-day rolling average basis at Dave Johnston Unit 4. We request that EPA provide a vendor statement confirming that this emission rate is a reasonable expectation for this boiler.

EPA has assumed that LNB+OFA can achieve 0.14 lb/mmBtu on an annual basis. However, the upgraded LNB w/SOFA, which began June 12, 2009, achieved 0.154 lb/mmBtu in 2012. In its 2007 BART submittal, PacifiCorp states:

> Reductions from higher baseline concentrations (inlet NOx) are lower in cost per ton, but result in higher operating costs because of greater reagent consumption. To reduce reagent costs, S&L has assumed that combustion modifications including LNBs and advanced OFA, capable of achieving a projected NOx

[5] Neither PacifiCorp nor WY DEQ proposed a retrofit factor for these units. EPA's application of the maximum retrofit factor (1.5) to Dave Johnston Units 1 and 2 is unsupported and leads to a significant $1.5 million/yr and $800/ton overestimation of average costs. It is especially surprising that EPA has applied the maximum retrofit factor to all four units at Dave Johnston, and that even an "end" unit like Unit 1 is considered to have the highest degree of retrofit difficulty. It has been our experience that end units are typically the easiest to retrofit, while the more difficult retrofits are associated with "middle" units. Once the SCR costs are corrected to address the issue discussed above, the incremental costs become $5,700 - $5,800/ton (versus $7,050/ton at Bridger #2).

> emission rate of 0.15 lb per MMBtu. At a further reduction of 20 percent in NOx, emission rates for SNCR would result in a projected emission rate of 0.12 lb per MMBtu.

A 20% reduction by SNCR from 0.154 lb/mmBtu yields 0.123 lb/mmBtu, not the 0.11 lb/mmBtu upon which EPA based its cost-effectiveness calculations. It appears that EPA has overestimated the ability of its BART proposal to reduce NO_X.

EPA's application of the maximum retrofit factor (1.5) to SCR on Dave Johnston Unit 4 is unsupported[6] and leads to a significant $3.8 million/yr and $900/ton overestimation of average costs. We disagree with EPA's decision to apply the maximum retrofit factor to all four units at Dave Johnston, and that even an "end" unit like Unit 4 is considered to have the highest degree of retrofit difficulty. It has been our experience that end units are typically the easiest to retrofit, while the more difficult retrofits are associated with "middle" units.

Once the SNCR effectiveness and SCR costs are corrected to address the issues discussed above, the incremental cost becomes $6,600/ton (versus $7,050/ton at Bridger #2). Under the EPA proposal, Dave Johnston Unit 4 would contribute over 0.7 dv impairment at Wind Cave National Park (and 0.5 dv at Badlands NP). With addition of SCR, impairment would drop to less than 0.50 dv. We believe that SCR is BART for Dave Johnston Unit 4.

Wyodak Power Plant

For Wyodak, EPA is proposing that the FIP NO_X BART is new LNBs with OFA plus SNCR at an emission limit of 0.17 lb/mmBtu. EPA proposes to eliminate new LNBs with advanced OFA plus SCR because:

> Although the cost-effectiveness and visibility improvement are within the range of other EPA FIP actions, we find that the cumulative visibility improvement of 1.16 deciviews for new LNBs with OFA plus SCR is low compared to the cumulative visibility benefits that will be achieved by requiring SCR at Dave Johnston Unit 3 (2.92 dv), Laramie River Unit 1 (2.12 dv), Laramie River Unit 2 (1.97 dv), Laramie River Unit 3 (2.29 dv), Naughton Unit 1 (3.54 dv), and Naughton Unit 2 (4.18 dv).

Because the cumulative visibility improvement from EPA's proposed control strategy is barely half of the visibility improvement that EPA rejected as "low," then visibility improvement cannot be the only factor relied upon by EPA in making its BART determination. We can only conclude that EPA is somehow relating visibility improvement to another factor. For example, after correcting for the unsupported 1.3 retrofit factor at this relatively simple, single-EGU facility, the cost-effectiveness of adding SCR is $16 million/dv at Wind Cave National Park, and $10 million/cumulative dv. By comparison, based upon EPA estimates, addition of SCR to Laramie River Unit 3 results in $28 million/dv at the most-impacted Class I area, and addition of SCR to Laramie River Unit 2 yields $10 million/cumulative dv. The cumulative cost-effectiveness of adding SCR to Wyodak is equivalent to EPA's accepted values at Laramie River Unit 2.

Based upon cost and visibility improvement, we believe that SCR is BART for Wyodak. Under the EPA proposal, Wyodak would still contribute over 0.7 dv impairment at Wind Cave National

[6] Neither PacifiCorp nor WY DEQ proposed a retrofit factor for this unit.

Park (and exceed 0.5 dv at Badlands National Park). With addition of SCR, impairment would drop to less than 0.50 dv at all Class I areas. As EPA stated in its FR Notice, "cost-effectiveness and visibility improvement are within the range of other EPA FIP actions." Even though cumulative visibility improvement is relatively low, so are SCR costs. Addition of SCR at Wyodak should be required because it is consistent with the other BART determinations EPA has made here.

Jim Bridger Power Plant

We commend EPA and the State for proposing addition of SCR to all four units at Jim Bridger. We note, however, that the remaining emissions would still result in a 1.8 dv impact at the nearest Class I area, and we have some concerns with the manner in which other factors (plans for system-wide controls and "affordability" issues) were brought into the BART analysis. Additionally, we request that EPA consider the use of more-effective SCR systems. (The proposed SCR systems would be 72% - 75% efficient.)

The Federal Register Notice states:

> EPA is proposing to determine that BART for all units at Jim Bridger would be SCR if the units were considered individually, based on the five factors, without regard for the controls being required at other units in the PacifiCorp system. However, when the cost of BART controls at other PacifiCorp-owned EGUs is considered as part of the cost factor for the Jim Bridger Units EPA is proposing that Wyoming's determination that NO_X BART for these units is new LNB plus OFA for is reasonable.

EPA is proposing to approve the SIP with regard to the State's determination that the appropriate level of NO_X control for all units at Jim Bridger for purposes of reasonable progress is the SCR-based emission limit in the SIP, with compliance dates of:

- December 31, 2015 for Unit 3
- December 31, 2016 for Unit 4
- December 31, 2021 for Unit 2
- December 31, 2022 for Unit 1

PacifiCorp asserted to the State during formulation of the SIP proposal, and has since asserted directly to EPA, that a number of factors, when considered together, suggest that requiring installation of SCR at Jim Bridger Units 1 and 2 earlier than 2021–2022 is not reasonable.

First, PacifiCorp points to the large number of retrofit actions it is taking at 20 coal-fired electric generating units in Wyoming, Utah, Colorado, and Arizona in order to reduce their emissions to comply with the regional haze SIPs that these states have submitted to EPA and with other regulatory requirements, including required controls for mercury and acid gases under the recent Mercury and Air Toxics Standards rule. The company asserts that there are high capital costs for the measures required for these air quality-improving retrofits. Moreover, PacifiCorp states that accelerating the required installation of SCR at Jim Bridger Units 1 and 2 to late 2017, rather than the 2021 and 2022 dates established by the State, would significantly increase the costs to the utility and to its customers.

Our analysis finds that PacifiCorp owns and operates 14 EGUs across Wyoming and Utah that have been subject to EPA actions, owns 100% of Cholla Unit 4 in Arizona, and partners with other utilities at four EGUs in Colorado. EPA is currently proposing SCR at six of the Wyoming EGUs, at Cholla Unit 4, and at three EGUs in Colorado. Also in Wyoming, combustion controls are proposed for two EGUs and SNCR for two EGUs. One Colorado EGU would install SNCR. We are not aware of any additional controls being proposed for any other PacifiCorp EGUs. Taking into account that PacifiCorp does not own 100% of all of the ten EGUs for which SCR has been proposed in Wyoming, Arizona, and Colorado, PacifiCorp effectively is responsible for adding SCR to the equivalent of 6.23 EGUs. By comparison, the American Electric Power consent decree requires relief at 16 of AEP's coal-fired power plants (46 units) by 2018.

PacifiCorp asserts that it has designed an installation schedule in order to minimize the number of units that are out of service system-wide for installation of emissions controls at any one time. Its goal, it asserts, is to be able to maintain service to its customers with an adequate capacity margin. PacifiCorp asserts that accelerating the timeline for installation of SCR would upset the orderly shut-down schedule they have devised and would threaten both service interruptions and an increased risk of spot-purchases of more expensive electrical energy, if it is available, to serve customers, but that either eventuality would significantly increase costs to its customers.

While we understand that PacifiCorp has made substantial past investments to reduce emissions from its power plants, and that it is facing significant new investments at several facilities, we are concerned about the manner in which this problem is being addressed, and the precedent that might be set.

We are very familiar with the "affordability" provisions of the BART Guidelines and have dealt with this issue in Arizona (Apache power plant) and Washington (Alcoa's Intalco primary aluminum smelter). In both of those cases, the company requesting the affordability exemption from BART provided extensive documentation (much of it confidential) to EPA and the FLMs to support its request. It was only after a thorough review by EPA that the affordability exemptions were approved. (We agreed.) In this case, it appears that the only information presented by PacifiCorp to support its request is its "assertions" discussed above. We believe that a more rigorous analysis is necessary in order for EPA, FLMs, and the public to be assured that the additional time being proposed by EPA is necessary and appropriate. For example, an important part of such an analysis would be the "installation schedule" that PacifiCorp has designed in order to minimize the number of units that are out of service system-wide for installation of emissions controls at any one time. Currently, the only schedule available in the docket is the July 2012 letter from PacifiCorp to EPA in which PacifiCorp simply reiterates the dates proposed for its "Installation Requirements." It is likely that PacifiCorp's actual installation schedule would show how scheduled routine outage periods would be used to install new equipment while minimizing construction costs and lost generation. For example, we would be surprised if PacifiCorp followed the schedule proposed by EPA for Jim Bridger, as this would entail halting construction (and moving construction equipment) for several years between installation of SCR on units 3 and 4 and on units 1 and 2.

FMC Westvaco and General Chemical Green River

Although the State and EPA determined that addition of combustion controls is BART for the three BART boilers at these two facilities, it is unclear how they arrived at these conclusions. The visibility improvement from EPA's proposed controls for the trona plants are less than the visibility improvement that EPA rejected as "low" in the EGU BART analyses, so it appears that EPA is using different criteria for these facilities or relating visibility improvement to another factor, which we assume to be some combination of cost and visibility improvement. (Otherwise, one would always choose the control strategy with the greatest visibility improvement.) However, it appears that EPA did not evaluate the cost analyses presented by the companies and the State, so we are concerned that the cost analyses for these two trona plants may suffer for the same problems that we pointed out to EPA before regarding the EGUs. For example, although Boiler D at Green River is the same size as the FMC boilers:

- FMC evaluated addition of new combustion controls in combination with SNCR or SCR, Green River did not.
- The capital cost of adding SNCR at Green River Boiler D is more than four times FMC.
- EPA presented cost-effectiveness of SNCR as $3,176/ton at Green River Boiler D. The actual cost-effectiveness, based on EPA's annual cost and emission reduction, is $1,637/ton.
- FMC assumed that SCR could reduce NO_X by 31% to 0.10 lb/mmBtu, Green River assumed 80% NO_X reduction to 0.14 lb/mmBtu. (EPA typically assumes that SCR can achieve 0.05 lb//Btu on an annual basis.)
- SCR capital cost is $43 million at FMC, $19 million for Green River Boiler D.
- EPA presented cost-effectiveness of SCR as $3,510/ton at Green River Boiler D. The actual cost-effectiveness, based on EPA's annual cost and emission reduction, is $2,339/ton.

It is apparent that EPA must have been considering the costs of controls, but, in view of the substantial discrepancies noted above, those costs are questionable. In view of these discrepancies, we question how EPA rejected the more-effective control technologies (SNCR and SCR) that produce greater visibility improvements for the proposed controls.

Appendix 1

Costs of Control

EPA states:

> In our revised cost analyses, we have followed the structure of the EPA Control Cost Manual, though we have largely used the Integrated Planning Model cost calculations to estimate direct capital costs and operating and maintenance costs.

Although we continue to recommend using as much of the CCM method as possible (e.g., the CCM method for estimating annual costs) to estimate SCR costs, we have observed that the IPM estimates are very similar to our results generated by the "hybrid" approach used to produce our previous comments. However, we are very surprised and concerned to see that EPA has introduced a retrofit factor greater than "1" (the default) for 13 of the 15 EGUs evaluated. The average retrofit factor used by EPA for the Wyoming EGUs is 1.33 (median = 1.30), with a maximum retrofit factor of 1.50 applied in six cases.

Chapter 2, "Cost Estimation: Concepts and Methodology" of the CCM provides a lengthy discussion of retrofit factors.[7] Finally, the CCM addresses SCR retrofits specifically "A

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[7] To quantify the unanticipated additional costs of installation not directly related to the capital cost of the controls themselves, engineers and cost analysts typically multiply the cost of the system by a retrofit factor. The proper application of a retrofit factor is as much an art as it is a science, in that it requires a good deal of insight, experience, and intuition on the part of the analyst.

The key behind a good cost estimate using a retrofit factor is to make the factor no larger than is necessary to cover the occurrence of unexpected (but reasonable) costs for demolition and installation. Such unexpected costs include - but are certainly not limited to - the unexpected magnitude of anticipated cost elements; the costs of unexpected delays; the cost of re-engineering and re-fabrication; and the cost of correcting design errors.

The magnitude of the retrofit factor varies across the kinds of estimates made as well as across the spectrum of control devices. At the study level, analysts do not have sufficient information to fully assess the potential hidden costs of an installation. At this level, a retrofit factor of as much as 50 percent can be justified. Even at detailed cost level (± 5 percent accuracy), vendors will not be able to fully assess the uncertainty associated with a retrofit situation and will include a retrofit factor in their assessments. For systems installed at the end of the stack, such as flares, retrofit uncertainty is seldom a factor. In these cases, an appropriate retrofit factor may be one or two percent of the TCI. In complicated systems requiring many pieces of auxiliary equipment, it is not uncommon to see retrofit factors of much greater magnitude can be used.

Since each retrofit installation is unique, no general factors can be developed. A general rule of thumb as a starting point for developing an appropriate retrofit factor is: The larger the system, the more complex (more auxiliary equipment needed), and the lower the cost level (eg. study level, rather than detailed), the greater the magnitude of the retrofit factor. Nonetheless, some general information can be given concerning the kinds of system modifications one might expect in a retrofit:
1. Auxiliary equipment. The most common source of retrofit-related costs among auxiliary equipment types comes from the ductwork related costs. In addition, to requiring very long duct runs, some retrofits require extra tees, elbows, dampers, and other fittings. Furthermore, longer ducts and additional bends in the duct cause greater pressure drop, which necessitates the upgrading or addition of fans and blowers.
2. Handling and erection. Because of a "tight fit," special care may need to be taken when unloading, transporting, and placing the equipment. This cost could increase significantly if special means (e.g., helicopters) are needed to get the equipment on roofs or to other inaccessible places.

correction factor for a new installation versus a retrofit installation is included to adjust the capital costs."[8] The CCM retrofit factor is \$728/mmBtu/hr. For medium-size boilers like Dave Johnston Unit 4 or Wyodak, this represents a 23% - 24% increase in the direct capital cost.

Background for Units Subject to BART

Basin Electric's (Basin) Laramie River Station (LRS)

Basin Electric's (Basin) Laramie River Station is comprised of three 590 MW (gross) dry-bottom, wall-fired boilers burning pulverized Powder River Basin sub-bituminous coal for a total gross generating capacity of 1,770 MW. Laramie River Unit 1 was placed in service in 1980. Unit 2 commenced service in 1981, and Unit 3 entered service in 1982. All units are BART-eligible. Each unit is equipped with early generation Low-NOx burners (LNBs) to control emission of NO_X. Over-Fire Air (OFA) was added to Unit 1 in 2009, Unit 2 in 2010, and Unit 3 in 2011. Units are also equipped with cold-side electrostatic precipitators (ESPs) to control particulate matter emissions. Units 1 and 2 are equipped with wet flue gas desulfurization (WFGD), and Unit 3 is equipped with a dry scrubber for SO_2 removal. The presumptive NO_X emission limit is 0.23 lb/mmBtu. According to CAMD, 2012 NO_x emissions from Laramie River were 12,188 tons which ranked the plant #29 in the U.S. Emissions are typically evenly

3. Piping, Insulation, and Painting. Like ductwork, large amounts of piping may be needed to tie in the control device to sources of process and cooling water, steam, etc. Of course, the more piping and ductwork required, the more insulation and painting will be needed.
4. Site Preparation. Site preparation includes the surveying, clearing, leveling, grading, and other civil engineering tasks involved in preparing the site for construction.
Unlike the other categories, this cost may be very low or zero, since most of this work would have been done when the original facility was built. However, if the site is crowded and the control device is large, the size of the site may need to be increased and then site preparation may prove to be a major source of retrofit-related costs.
5. Off-Site Facilities. Off-site facilities should not be a major source of retrofit costs, since they are typically used for well-planned activities, such as the delivery of utilities, transportation, or storage.
6. Engineering. Designing a control system to fit into an existing plant normally requires extra engineering, especially when the system is exceptionally large, heavy, or utility-consumptive. For the same reasons, extra supervision may be needed when the installation work is being done.
7. Lost Production. The shut-down for installation of a control device into the system should be a well-planned event. As such, its cost should be considered a part of the indirect installation cost (start-up). However, unanticipated problems with the installation due to retrofit-related conditions can impose significant costs on the system. (For example, consider a pollution control device to be installed in the middle of a stack. After shutting down the plant, removing a section of the stack reveals it has been worn too thin to weld the device to it, necessitating the fabrication and replacement of a major portion of the stack.) The net revenue (i.e., gross revenue minus the direct costs of generating it) lost during this unanticipated shutdown period is a bonafide retrofit expense.

Due to the uncertain nature of many estimates, analysts may want to add an additional contingency (i.e., uncertainty) factor to their estimate. However, the retrofit factor is a kind of contingency factor and the cost analyst must be careful to not impose a double penalty on the system for the same unforseen conditions. Retrofit factors should be reserved for those items directly related to the demolition, fabrication, and installation of the control system. A contingency factor should be reserved (and applied to) only those items that could incur a reasonable but unanticipated increase but are not directly related to the demolition, fabrication, and installation of the system. For example, a hundred year flood may postpone delivery of materials, but their arrival at the job site is not a problem unique to a retrofit situation.
[8] Section 4, NOx Controls, Section 4.2, NOx Post- Combustion, Chapter 2, Selective Catalytic Reduction

distributed among the three EGUs. There are seven Class I areas within 300 km of the Laramie River Station:

- Badlands National Park
- Eagles Nest Wilderness Area
- Flat Tops Wilderness Area
- Mount Zirkel Wilderness Area
- Rawah Wilderness Area
- Rocky Mountain National Park
- Wind Cave National Park

Naughton Power Plant

PacifiCorp's Naughton Power Plant (Naughton) is comprised of three tangentially-fired units burning sub-bituminous coals with a total gross generating capacity of 770 megawatts (MW).[9] According to CAMD, 2012 NO_x emissions from Naughton were 8,311 tons which ranked the plant #57 in the U.S. There are seven Class I areas within 300 km of Naughton:

- Bridger Wilderness Area
- Craters of the Moon National Monument
- Fitzpatrick Wilderness Area
- Grand Teton National Park
- Teton Wilderness Area
- Washakie Wilderness Area
- Yellowstone National Park

Naughton Unit 1 commenced operation in 1963 and can generate at least 174 MW. It was originally constructed with a Research Cottrell mechanical dust collector to control particulate matter emissions, and in 1974 a Lodge Cottrell ESP was added to further reduce particulate emissions. A new WFGD system and LNB w/ Separated OFA (SOFA) began operation June 8, 2012. 2012 NO_x emissions were 1,803 tons which ranked the EGU #286 in the U.S.

Naughton Unit 2 commenced operation in 1968 and can generate at least 229 MW. It was originally constructed with a United Conveyor mechanical dust collector to control particulate matter emissions and in 1976 a Lodge Cottrell ESP was added to further reduce particulate emissions. A new WFGD system and LNB w/SOFA began operation October 1, 2011. 2012 NO_x emissions were 1,797 tons which ranked the EGU #287 in the U.S.

Naughton Unit 3 commenced operation in 1971 and can generate at least 369 MW. The unit was retrofitted with ALSTOM LCCFS II LNB in 1999. Particulate emissions are controlled using a Buell weighted wire ESP and Flue Gas Conditioning (FGC). SO_2 emissions are controlled using

[9] Based on EPA's Clean Air Markets data for 2001 – 2003. Data for 2008 – 2011 show that Naughton units continued to generate in excess of 750 MW when individual unit maxima are summed.

low sulfur coal and a UOP LLC two-tower sodium-based WFGD system that was installed in 1997. 2012 NO_x emissions were 4,711 tons which ranked the EGU #69 in the U.S.

PacifiCorp recently received an air quality permit to modify the three Naughton units. Unit 2 will also be equipped with new state-of-the-art LNB systems with advanced OFA and FGC systems to help improve the particulate removal efficiency of the existing ESPs on each of the units. New WFGD systems will be installed on Naughton Unit 2. The existing ESP on Naughton Unit 3 will be replaced with a new full-scale fabric filter at which time the existing FGC system will be removed.

Dave Johnston Power Plant

PacifiCorp's Dave Johnston Power Plant (Johnston) is comprised of four units burning pulverized sub-bituminous Powder River Basin coal for a total gross generating capacity of (at least) 852 megawatts (MW) based upon 2001 - 2003 data from CAMD. According to CAMD, 2012 NO_x emissions from Johnston were 6,999 tons which ranked the plant #72 in the U.S. There are seven Class I areas within 300 km of Johnston:

- Badlands National Park
- Bridger Wilderness Area
- Mount Zirkel Wilderness Area
- Rawah Wilderness Area
- Rocky Mountain National Park
- Washakie Wilderness Area
- Wind Cave National Park

Johnston Units 1 and 2 are dry bottom wall-fired units that generated up to 119 and 116 MW, respectively, during 2001 – 2003. Unit 1 began operation in 1958 and Unit 2 in 1960. Since both units were in operation before August 7, 1962 they are not subject to BART regulation. SO_2 emissions are uncontrolled and 2012 emissions averaged 0.8 lb/mmBtu. NO_X emissions are uncontrolled and 2012 emissions averaged 0.4 lb/mmBtu. PM emissions are controlled using an ESP. According to CAMD, 2012 NO_x emissions from Johnston Units 1 and 2 were 1,602 and 1,853 tons, respectively, which ranked these units #317 and #282 in the U.S.

Johnston Unit 3 commenced service in 1964 and is subject to BART review. It was manufactured by Babcock & Wilcox and equipped with burners in a cell configuration. (It is the only boiler in Wyoming subject to BART with burners in a cell configuration.) During 2001 – 2003, Johnston Unit 3 generated up to 251 MW. The original burners were upgraded to LNB technology w/OFA which began May 23, 2010. The presumptive NO_X limit is 0.45 lb/mmBtu and 2012 emissions averaged 0.21 lb/mmBtu. According to CAMD, 2012 NO_x emissions were 1,701, which ranked #301 in the U.S. Johnston Unit 3 was not equipped with any SO_2 control equipment until a dry Lime FGD began on May 29, 2010 and 2012 emissions averaged 0.09 lb/mmBtu. PM emissions from Unit 3 were controlled using a Lodge-Cottrell single-chamber ESP installed in 1976 until a fabric filter was installed in 2011.

Johnston Unit 4 is a tangentia lly-fired boiler manufactured by Combustion Engineering, (now Alstom) and commenced service in 1972 and is subject to BART review. During 2001 – 2003, Johnston Unit 4 generated up to 366 MW. The original burners were replaced in 1976 with concentric-firing first generation LNB and were upgraded to LNB Technology w/SOFA which began Jun 12, 2009. The presumptive NO_X limit is 0.15 lb/mmBtu (30-day rolling average) and 2012 emissions averaged 0.154 lb/mmBtu. According to CAMD, 2012 NO_x emissions were 1,843, which ranked #284 in the U.S. On April 23, 2012, a Dry Lime FGD and baghouse replaced a Venturi scrubber to control SO_2 and PM emissions.

Wyodak Power Plant

PacifiCorp's Wyodak Power Plant is comprised of one dry-bottom wall-fired EGU burning pulverized sub-bituminous Powder River Basin coal with a gross generating capacity of (at least) 395 megawatts (MW) based upon 2001 - 2003 data from CAMD. Although presumptive BART does not apply to this power plant with less than 750 MW capacity, the presumptive NO_X limit for this EGU is 0.23 lb/mmBtu. According to CAMD, 2012 NO_x emissions from Wyodak were 3,051 tons which ranked the plant #151 in the U.S. There are three Class I areas within 300 km of Wyodak:

- Badlands National Park
- Washakie Wilderness Area
- Wind Cave National Park

Wyodak's EGU was manufactured by Babcock & Wilcox and commenced service in 1978. NO_X emissions from the boiler are currently controlled with Alstom TFS 2000® LNB Technology w/OFA which began Apr 18, 2011. PM emissions were controlled using an ESP until Apr 18, 2011 when it was replaced by a fabric filter. SO_2 emissions are controlled using a Joy Niro, three-tower lime-based spray dryer installed in 1986.

Jim Bridger Power Plant

PacifiCorp's Jim Bridger Power Plant (Bridger) is comprised of four identically-sized tangentially-fired boilers burning sub-bituminous coal with a total generating capacity of 2,251 megawatts (MW).[10] According to CAMD, 2012 NO_x emissions from Bridger were 13,762 tons which ranked the plant #17 in the U.S. Emissions were relatively evenly distributed among the four units, ranking them each #104 - #142 across the US. There are eleven Class I areas within 300 km of Bridger:

- Bridger Wilderness Area
- Eagles Nest Wilderness Area
- Fitzpatrick Wilderness Area
- Flat Tops Wilderness Area

[10] Based on EPA's Clean Air Markets data for 2001 – 2003. Data for 2008 – 2011 show that Naughton units continued to generate in excess of 750 MW when individual unit maxima are summed.

- Grand Teton National Park
- Mt. Zirkel Wilderness Area
- Rawah Wilderness Area
- Rocky Mountain National Park
- Teton Wilderness Area
- Washakie Wilderness Area
- Yellowstone National Park

Unit 1 was placed in service in 1974. Unit 2 commenced service in 1975. Unit 3 entered service in 1976 followed by Unit 4, which commenced service in 1979. All units are BART-eligible. Each unit was initially equipped with early generation LNB manufactured by Combustion Engineering to control emissions of NO_X. They are also equipped with dry Flakt wire-frame ESPs to control PM. Finally, to control SO_2 emissions, each unit is equipped with a three-absorber-tower WFGD system made by Babcock & Wilcox.

On April 1, 2005, Permit MD-1138 was issued by WY DEQ to PacifiCorp to replace the first generation LNB on Unit 2 with a new low-NO_X firing system including two elevations of SOFA. The new LNB were installed and placed into service May 29, 2005. The permitted NO_X emission limit of 0.26 lb/mmBtu, annual average, authorized in MD-1138 for Unit 2 went into effect in 2005.

On October 6, 2006, after the LNB modification to Unit 2 was completed, PacifiCorp submitted a construction permit application to modify Units 1, 2, 3 and 4 by replacing the existing first generation LNBs on Units 1, 3 and 4 with LNB with two elevations of SOFA, install FGC which injects SO_3 gas into the flue gas to improve the efficiency of the ESPs on Units 1-4, and upgrade the existing FGD systems on all four units to achieve greater than 90% SO_2 removal.

Permit MD-1552 was issued by WY DEQ on April 9, 2007 authorizing the new LNB, FGC, and WFGD modifications to Bridger. The LNB upgrades to Unit 3 started up May 30, 2007. The new LNBs on Unit 4 started up June 8, 2008. The final LNB upgrade occurred in 2010 on Unit 1.

Modifications to the scrubber vessels on Unit 4 were not necessary in order to meet the SO_2 emission limits permitted in MD-1552. Unit 4 can meet the limits by reducing the amount of flue gas bypassing the scrubber. However, this would increase the moisture content of the gas entering the exhaust stack and modifications to the stack drain system were required to accommodate the increased moisture. Upon completion of wet scrubber upgrades permitted in MD-1552, the SO_2 limits for the corresponding unit became 0.15 lb/mmBtu on a 12-month rolling average and 900 lb/hr on a 24-hr rolling average.

FMC Westvaco and General Chemical Green River

FMC's Westvaco facility is a trona mine and sodium products plant located in Sweetwater County, Wyoming. FMC Westvaco has two existing coal-fired boilers, Unit NS–1A and Unit NS–1B, that are subject to BART. Unit NS–1A and Unit NS–1B each have a design heat input rate of 887 mmBtu/hr and were constructed in 1975. They are both wall-fired, wet-bottom boilers burning subbituminous coal. Units NS–1A and NS–1B are currently controlled with combustion air control with a permit limit of 0.7 lb/mmBtu (3- hour rolling average). Baseline NO_X emissions are 2,719.5 tpy for each unit based on a heat input rate of 887 mmBtu/hr and 8,760 hours of operation per year. The State determined that LNBs plus OFA are reasonable for BART at 0.35 lb/mmBtu (30- day rolling average). According to EPA, although the cost-effectiveness for SNCR is reasonable, it was reasonable for the State not to select this control technology based on the incremental visibility improvement for this control technology.

General Chemical Green River is a trona mine and sodium products plant. General Chemical's two existing coal-fired boilers, C and D, are co-located at the facility power plant. Both boilers are tangentially fired and burn low sulfur bituminous coal and they supply power and process steam to mining and ore processing operations. The firing rate is 534 mmBtu/hr for Boiler C and 880 mmBtu/hr for Boiler D. Boiler C and Boiler D are currently controlled with LNBs plus OFA with a permit limit of 0.7 lb/mmBtu (3-hour rolling average). The State determined that NO_X BART is the existing LNBs with new SOFA at emission limits for Boiler C and Boiler D of 0.28 lb/ (30-day rolling average) each. According to EPA, although the cost-effectiveness for SNCR and SCR is reasonable, it was reasonable for the State not to select this control technology based on the low visibility improvement for these control technologies.